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IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY AND FOR RELATED APPROVALS, AUTHORIZATIONS AND WAIVERS.	DOCKET NO. E-01933A-98-0471
IN THE MATTER OF THE FILING OF TUCSON ELECTRIC POWER COMPANY OF UNBUNDLED TARIFFS PURSUANT TO A.C.C. R14-2-1061 *ET. SEQ.*	DOCKET NO. E-01933A-98-0772
IN THE MATTER OF COMPETITION IN THE PROVISION OF ELECTRIC SERVICES	DOCKET NO. RE-00000C-94-0165

COMMENTS OF ENRON CORP. ON PROPOSED SETTLEMENT

Pursuant to the Procedural Order issued on June 23, 1999 in this proceeding, Enron Corp. and its affiliate, Enron Energy Services, Inc. (jointly referred to as "Enron") hereby file Comments on the Proposed Settlement filed by Tucson Electric Power Company and others. In support thereof, Enron submits the following.

On June 10, 1999, Tucson Electric Power Company ("TEP") filed with the Arizona Corporation Commission ("Commission") a Notice of Filing, Application for Approval of Settlement Agreement and Request for Expedited Procedural Order. The proposed Settlement addresses stranded costs, unbundled rates, phase-in of retail service and other provisions that would implement electric competition on TEP's system. The June 23, 1999 Procedural Order directed intervening parties to file specific disagreements, testimony or comments regarding the

Proposed Settlement. On or about June 24, 1999, Enron filed an application for leave to intervene in this proceeding.

Enron has reviewed the Settlement and we find the Settlement falls short in its attempt to create a competitive market for customers who would choose direct access service. Enron certainly does not oppose resolving stranded costs and creating competitive markets through settlement, however, the goals and objectives of the introduction of retail competition should not be lost in the bargain. While Enron recently filed testimony in the restructuring settlement case filed by Arizona Public Service (Docket No. E-01345A-98-0473 *et al.),* we are limiting ourselves to filing comments in this case at this point in time. There are two reasons for this. First, the shortcomings in the instant settlement as we see them are far less serious than those in the APS case. Second, the issues as we perceive them involve policy calls by the Commission, not factual determinations. Accordingly, the Commission is able to resolve the issues raised in these comments without the need for a formal, on-the-record proceeding.

As a policy matter, the Commission should not approve a restructuring settlement unless it (1) assures that all potential suppliers have fair access to customers; (2) assures that all potential suppliers have fair access to the wires: (3) identifies and addresses market power in generation; (4) gives customers the opportunity to purchase electric services from a supplier of their choice; (5) informs customers of what they pay the utility for each service so they can compare different providers; (6) prevents subsidization of unregulated services by regulated services; and (7) resolves disputes over stranded costs.[1] As discussed below, the Settlement fails to adequately address some of these points.

A. Shopping Credits

1. The Settlement Does Not Permit an Evaluation of Whether the Shopping Credit is Adequate for all Customers.

One aspect of the TEP Settlement which is critical to the success of the competitive market is the market generation credit and its "adder" which create in effect the shopping credit available to customers who wish to purchase their generation from suppliers other than TEP. The shopping credit available to ESP customers is the difference between the standard offer bundled rate and the direct access tariff rate. If a shopping credit is set too low, then ESPs simply cannot compete against the standard offer. If the elements of the direct access tariff are not properly unbundled and priced, then the shopping credit is artificially squeezed. If proper allowance is not made for the additional costs of marketing power to retail customers, the shopping credit will not allow ESPs to bring price savings or competitive products to consumers.

The Settlement sets a market generation credit and an adder which together form the shopping credit available to ESPs. The Settlement acknowledges that the adder's purpose is to estimate the cost of supplying power to a specific customer or customer group and stratum relative to the value of the NYMEX future prices used in the calculation of the market price for a 100% load factor. Section 2.1(e) of the Settlement states that the MGC and the adder will be adjusted for each customer class (which may be further divided into class strata or in some cases by large customer) for differences between the class load factor and the system average load factor. The Settlement does not offer the specifics of how this adjustment will be calculated. Without this explanation, there is no way to determine whether the adder will be adequate for particular customers once this adjustment is performed. This uncertainty makes it almost

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[1] This list of issues appears in the Testimony of Staff Witness Lee Smith as filed in Docket No. E-01345A-98-0473, et al. on June 30, 1999, at p.2.

impossible for competitors at this time to evaluate whether they can offer product and service to TEP's retail customers.

2. <u>The Adder May Not Be Adequate if Future Costs are Imposed on ESPs</u>.

Section 2.1(f) of the Settlement provides that "the Adder is intended to estimate the difference between the flat load costs associated with the PV [Palo Verde] index and actual customer load characteristics plus an additional amount for costs that will not be readily quantifiable until the Arizona market more fully develops. It is not clear what is meant by the "additional amount for costs that will not be readily quantifiable until the Arizona market more fully develops." In Enron's view, the adder should reflect the differential discussed above, as well as retailing costs (e.g. customer care, marketing, procurement and scheduling) and all other costs directly charged to an ESP or its Scheduling Coordinator. The proposed adder does not sufficiently cover the load factor differential as well as all these other costs. The Settlement should be clarified to state that the current adder only covers the load factor differential and unquantified retail costs. Any additional charges in the future directly levied on an ESP and/or its Scheduling Coordinator should be separately included in either the adder or the MGC. For example, the charges the ESP or its Scheduling Coordinator will pay for AISA service, when the AISA becomes operational, should either be directly reflected in the adder or indirectly credited to the ESP through the calculation of the floating CTC rate. If it is the intent of the parties to the Settlement that the adder cover both the load factor differentials and future unforeseen charges to the ESP (or its Scheduling Coordinator), then the adder may not adequately reflect retailing costs for the generation component of TEP's standard offer service or that of the ESPs.

3. <u>The Adder Should Reflect Savings to TEP, and Costs to ESPs, for Uncollectible Expenses.</u>

The Settlement must also be modified to enhance the MGC and adder to reflect the impact of ESP's on TEP's uncollectible expense. Since ESPs will be providing the generation component of service to a direct access customer, TEP's uncollectible exposure for that generation component is reduced, and that of the ESP is increased. The MGC and adder must not only be adjusted for losses, as provided for in the Settlement, but for uncollectibles as well. This can be done by grossing up the MGC and the adder by an uncollectibles factor.[2] Further, to the extent that franchise fees will be paid directly by the ESPs for generation, and are thus avoided by TEP, a similar adjustment should be made to the MGC and adder.

The uncertainty inherent in calculating the adder for specific customers will frustrate the ESPs' attempts to market to TEP's customers. The Settlement should be modified to specifically address this calculation and parties should have an opportunity to react to the results of this modification, and to argue whether does or does not present sufficient shopping credits for the market. Further, the Settlement should be clarified to require additional adjustments for future charges which the ESP may incur (directly or through its Scheduling Coordinator), or the adder should be adjusted to reflect retailing costs associated with providing generation service to retail customers.

B. <u>Metering and Billing Credits</u>

1. <u>Metering and Billing Credits Must be Set Under Embedded Cost Methodology.</u>

The establishment of credits for revenue cycle services such as billing, meter reading and metering is a significant aspect of the competitive electric retail market. At least for some period of time, the utility will be offering standard offer service and direct access services

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[2] We note that in the case where an ESP is performing consolidated billing, i.e., billing the retail customer for both its charges and those of TEP, the uncollectible risk to TEP is also reduced. This savings to TEP and cost to the ESP must be reflected in the billing credit the ESP receives.

simultaneously, and will also make available these revenue cycle services to the direct access customers if requested. It stands to reason, then, that if the ESP is willing and able to provide the revenue cycle services itself, it should avoid those costs from TEP. An efficient ESP should be able to provide these services for lower prices than the utility, and should also be able to bring these savings to the customer. To achieve this, the credits which are generated when the ESP performs these services must be set at the utility's embedded cost for providing these services, so that more efficient ESPs get the proper price signals and marketing opportunities. If the credits are less than the fully embedded cost of such service, then the direct access customers not taking the revenue cycle services from the utility are still subsidizing those services in their rates, squeezing out the possibility that an ESP can offer those services competitively. The Settlement does not stipulate whether the credits for unbundled metering and billing charges (which are the credits to the direct access bill when the ESP provides those services itself) are based on embedded costs or avoided costs, albeit they do seem lower than fully embedded credits would be. TEP should be directed to set the revenue cycle service credits at the fully embedded cost basis.

2. <u>Interval Metering Requirements Must be Clarified.</u>

A correctly set metering credit becomes even vital more if ESPs are required to install certain types of meters for certain customers. If the credit allowed is less than the cost of the metering the ESP must do, then the insufficient credits create a significant barrier to competition.

The Electric Competition Rules as proposed in Section R14-2-1612 provide that in lieu of hourly consumption measurement meters for competitive customers over 20 kW, "predictable loads will be permitted to use load profiles to satisfy the requirements for hourly consumption data." TEP has not included load profiles in its tariffs. The load profile requirement for relaxation of the hour consumption measurement meters must be clarified, and load profiles provided, so that ESPs can ascertain whether the metering credits are workable.

C. Stranded Costs

1. Stranded Cost Amounts to be Recovered under the Settlement Should be Fixed in the Settlement.

Article 2 of the Settlement creates two CTC's to collect TEP's stranded costs. The Fixed CTC will be set as 0.93 cents/KWh (average) and will terminate when it has yielded recovery of $450 million. The Floating CTC is calculated based on a market generation credit methodology and will terminate on a date certain, December 31, 2008. There is no set amount to be recovered under the Floating CTC.

Under Section 3.1 of the Settlement, on or before December 31, 2002, TEP shall transfer its competitive assets to a subsidiary at market value. If those assets are given a market value on that date, then it stands to reason that TEP's stranded costs should be calculated as the difference between market value and book value at the time of that transfer. TEP should be allowed to recover only that amount through the combination of its fixed and floating CTCs. Of course, anything collected through the floating CTC up to the time that stranded costs are determined would be subtracted from the total and only the remainder would be allowed for collection. If the stranded cost recovery is of a fixed amount, then the Floating CTC will terminate when that amount is collected. This gives the market a chance to be rid of the floating CTC earlier than December 31, 2008, should the target amount be recovered before that amount. It also prevents any windfall recovery to TEP should it collect more than the allowed stranded cost amount through the Floating CTC.

2. <u>The Settlement Should Specify Both the Competitive Assets to Be Transferred and the Methodology that Will be Used to Determine their Market Value for Transfer Purposes</u>.

Two additional clarifications should be made to the Settlement concerning stranded cost valuation and collection. First, TEP should be required to identify those assets it has determined to qualify as generation and other competitive assets and which will be transferred to its affiliates. This is an important exercise because parties may disagree as to the classification of competitive assets and this should be aired and resolved before the Settlement is finally approved. As TEP will be providing a bundled sales service even as it becomes a "wires" company, it could, by retaining "competitive assets" in its regulated wires company, keep to itself the inherent advantages of such assets which could translate into a competitive advantage in its standard offer. For example, if TEP had a power purchase or exchange contract with advantageous terms, this could be used to keep the cost of standard offer service below market prices. Identification of the assets TEP is planning to retain and those it will transfer will help to prevent anti-competitive ramifications of the utility retaining assets, which are properly deemed as competitive.

Second, TEP should specify exactly what methodology it plans to use to determine the market value of the competitive assets it will transfer under Section 3.1 of the Settlement. Certainly parties will differ on what methodologies are accurate or appropriate or yield the best measure of market value. The Commission and all affected parties should know what methodology TEP is proposing to use and should have an opportunity to address the validity of this valuation methodology before the Settlement is approved. This would ensure that there are no unfair surprises or disagreements at a later date, when TEP actually transfers those assets off of its books.

D. The Code of Conduct Should Be Modified To Prevent Undue Preference or Abuse.

Pursuant to Section 7.1 of the Settlement, TEP filed an Interim Code of Conduct after it filed its Settlement. While this Code does attempt to address the general areas of potential affiliate preference, there are some provisions that need clarification or strengthening in order to be effective.

Section 2 of the Code of Conduct provides that any non-customer-specific non-public information shall be made contemporaneously available by TEP to its affiliates and non-affiliates on the same terms and conditions. Enron would request that this section be amended to specify where information which TEP must make available to non-affiliate service providers will be found. For example, if TEP e-mails some "non-customer specific non-public information" to its competitive electric affiliate and also posts that information on some obscure website on the Internet, the non-affiliated ESPs may never find it. TEP should maintain a particular web address for such postings or should be required to send this information electronically or by facsimile to all interested ESPs in order to ensure that no one party receives preferential treatment by receiving this information in an advantageous manner. This same comment goes to Section 11 of the Code of Conduct, which deals with both customer-specific and non-customer specific information that TEP might give to a competitive electric affiliate.

Section 5 of the Code of Conduct allows TEP to share with affiliates joint corporate oversight, governance, support systems and personnel, provided that shared support is priced in a manner that permits clear identification of each company's portion of purchases and in accordance with applicable Commission allocation and reporting rules. Last week NARUC passed a resolution adopting "Guidelines for Cost Allocation and Affiliate Transactions." A copy of this resolution is attached hereto for consideration along with proposed Interim Code of

Conduct. While it may not be the only way to address this issue, this resolution would be useful in assessing Paragraph 5 of the Proposed Interim Code of Conduct and in providing more guidance on allocation and reporting requirements.

WHEREFORE, in light of the foregoing, Enron respectfully requests that the Commission consider these comments and modify the Settlement in accordance with the discussion above.

Dated: July 27, 1999

Respectfully submitted,

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By [signature]
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RESOLUTION REGARDING COST ALLOCATION GUIDELINES FOR THE ENERGY INDUSTRY

WHEREAS, there is ongoing concern regarding potential cross-subsidization between the regulated monopoly operations and the non-regulated businesses of electric and gas utilities; and

WHEREAS, utilities are adopting various business strategies to adjust to the changing retail markets, including forming alliances and creating subsidiaries, divisions and partnerships to participate in non-regulated, competitive markets; and

WHEREAS, state utility commissions are examining and adopting various policies to monitor the competitive activities of regulated energy utilities; and

WHEREAS, state utility commissions are examining and adopting policies and rules concerning potential cross-subsidies between regulated utilities and non-regulated affiliates including pricing of assets, products and services; and

WHEREAS, the National Association of Regulatory Commissioners (NARUC) requested the Staff Subcommittee on Accounts together with the Staff Subcommittees on Strategic Issues and Gas to prepare for NARUC's consideration, "Guidelines for Energy Cost Allocations"; and

WHEREAS, the Staff Subcommittee on Accounts together with the Subcommittee on Gas and Strategic Issues have prepared for NARUC's consideration "Guidelines for Cost Allocations and Affiliate Transactions", and

WHEREAS, each state or federal regulatory commission may have unique situations and circumstances that govern affiliate transactions, cost allocations, and/or service or product pricing; and

WHEREAS, the "Guidelines for Cost Allocations and Affiliate Transactions" are to provide guidance to the states and are not intended to be rules or regulations prescribing how cost allocations and affiliate transactions are to be handled; and

WHEREAS, the Staff Subcommittees on Accounts, ~~with the Staff Subcommittee on~~ Strategic Issues, and Gas should periodically review the Guidelines for Cost Allocations and Affiliate Transactions, taking into consideration the progression of competition in the electric and gas industries nationally, and report their findings, including proposed changes to the guidelines, if necessary, that promote efficiency in competitive energy markets while guarding against cross-subsidization by monopoly ratepayers; hereby be it

RESOLVED, the NARUC assembled in its 1999 Summer Committee Meetings in San Francisco, CA, adopts the attached "Guidelines for Cost Allocations and Affiliate Transactions"; and be it further

GUIDELINES FOR COST ALLOCATIONS AND AFFILIATE TRANSACTIONS

The following Guidelines for Cost Allocations and Affiliate Transactions (Guidelines) are intended to provide guidance to jurisdictional regulatory authorities and regulated utilities and their affiliates in the development of procedures and recording of transactions for services and products between a regulated entity and affiliates. The prevailing premise of these Guidelines is that allocation methods should not result in subsidization of non-regulated services or products by regulated entities unless authorized by the jurisdictional regulatory authority. These Guidelines are not intended to be rules or regulations prescribing how cost allocations and affiliate transactions are to be handled. They are intended to provide a framework for regulated entities and regulatory authorities in the development of their own policies and procedures for cost allocations and affiliated transactions. Variation in regulatory environment may justify different cost allocation methods than those embodied in the Guidelines.

The Guidelines acknowledge and reference the use of several different practices and methods. It is intended that there be latitude in the application of these guidelines, subject to regulatory oversight. The implementation and compliance with these cost allocations and affiliate transaction guidelines, by regulated utilities under the authority of jurisdictional regulatory commissions, is subject to Federal and state law. Each state or Federal regulatory commission may have unique situations and circumstances that ~~dictate~~ govern affiliate transactions, cost allocations, and/or service or product pricing standards. For example, The Public Utility Holding Company Act of 1935 requires registered holding company systems to price "at cost" the sale of goods and services and the undertaking of construction contracts between affiliate companies.

The Guidelines were developed by the NARUC Staff Subcommittee on Accounts in compliance with the Resolution passed on March 3, 1998 entitled "Resolution Regarding Cost Allocation for the Energy Industry" which directed the Staff Subcommittee on Accounts together with the Staff Subcommittees on Strategic Issues and Gas to prepare for NARUC's consideration, "Guidelines for Energy Cost Allocations." In addition, input was requested from other industry parties. Various levels of input were obtained in the development of the Guidelines from the Edison Electric Institute, American Gas Association, Securities and Exchange Commission, the Federal Energy Regulatory Commission, Rural Utilities Service and the National Rural Electric Cooperatives Association as well as staff of various state public utility commissions.

In some instances, non-structural safeguards as contained in these guidelines ~~within~~ may not be sufficient ~~in~~ to preventing market power problems in strategic markets such as the generation market. Problems arise when a firm has ~~Market power is defined as~~ the ability to raise prices above market for a sustained period and/or impede output of a product or service. ~~Consideration should be given to any "unique" advantages and incumbent utility would have over competitors in an emerging market such as the retail energy market. A code of conduct should be used in conjunction with guidelines on cost allocations and affiliate transactions. Such concerns have led some states to develop codes of conduct to govern relationships between the regulated utility and its non-regulated affiliates.~~ Such concerns have led some states to develop codes of conduct to govern relationships between the regulated utility and its non-regulated affiliates. Consideration should be given to any "unique" advantages an incumbent utility would have over competitors in an emerging market such as the retail energy market. A code of conduct should be used in conjunction with guidelines on cost allocations and affiliate transactions.

A. DEFINITIONS

1. Affiliates - companies that are related to each other due to common ownership or control.

2. Attestation Engagement - one in which a certified public accountant who is in the practice of public accounting is contracted to issue a written communication that expresses a conclusion about the reliability of a written assertion that is the responsibility of another party.

3. Cost Allocation Manual (CAM) - an indexed compilation and documentation of a company's cost allocation policies and related procedures.

4. Cost Allocations - the methods or ratios used to apportion costs. A cost allocator can be based on the origin of costs, as in the case of cost drivers; cost-causative linkage of an indirect nature; or one or more overall factors (also known as general allocators).

5. Common Costs - costs associated with services or products that are of joint benefit between regulated and non-regulated business units.

6. Cost Driver - a measurable event or quantity which influences the level of costs incurred and which can be directly traced to the origin of the costs themselves.

7. Direct Costs - costs which can be specifically identified with a particular service or product.
8. Fully Allocated costs - ~~services or products bear~~ the sum of the direct costs plus an appropriate share of indirect costs.

9. Incremental pricing - pricing services or products on a basis of only the additional costs added by their operations while one or more pre-existing services or products support the fixed costs.

10. Indirect Costs - costs that cannot be identified with a particular service or product. This includes but not limited to overhead costs, administrative and general, and taxes.

11. Non-regulated - ~~refers to services and products that are~~ that which is not subject to regulation by regulatory authorities.

12. Prevailing Market Pricing - a generally accepted market value that can be substantiated by clearly comparable transactions, auction or appraisal.

13. Regulated - ~~refers to services and products that are not~~ that which is subject to regulation by regulatory authorities.

14. Subsidization - the recovery of costs from one class of customers or business unit that are attributable to another.

B. COST ALLOCATION PRINCIPLES

The following allocation principles should be used whenever products or services are provided between a regulated utility and its non-regulated affiliate or division.

1. To the maximum extent practicable, in consideration of administrative costs, costs should be collected and classified on a direct basis for each asset, service or product provided.

2. The general method for charging indirect costs should be on a fully allocated cost basis. Under appropriate circumstances, regulatory authorities may consider incremental cost, prevailing market pricing or other methods for allocating costs and pricing transactions among affiliates.

3. To the extent possible, all direct and allocated costs between regulated and non-regulated services and products should be traceable on the books of the

applicable regulated utility to the applicable Uniform System of Accounts. Documentation should be made available to the appropriate regulatory authority upon request regarding transactions between the regulated utility and its affiliates.

4. The allocation methods should apply to the regulated entity's affiliates in order to prevent subsidization from, and ensure equitable cost sharing among the regulated entity and its affiliates, and vice versa.

5. All costs should be classified to services or products which, by their very nature, are either regulated, non-regulated, or common to both.

6. The primary cost driver of common costs, or a relevant proxy in the absence of a primary cost driver, should be identified and used to allocate the cost between regulated and non-regulated services or products.

7. The indirect costs of each business unit, including the allocated costs of shared services, should be spread to the services or products to which they relate using relevant cost allocators.

C. COST ALLOCATION MANUAL (NOT TARIFFED)

Each entity that provides both regulated and non-regulated services or products should maintain a cost allocation manual (CAM) or its equivalent and notify the jurisdictional regulatory authorities of the CAM's existence. The determination of what, if any, information should be held confidential should be based on the statutes and rules of the regulatory agency that ~~maintains~~ requires the information. Any entity required to provide notification of a CAM(s) should make arrangements as necessary and appropriate to ensure competitively sensitive information derived therefrom be kept confidential by the regulator. At a minimum, the CAM should contain the following:

1. An organization chart of the holding company, depicting all affiliates, and regulated entities.

2. A description of all assets, services and products provided to and from the regulated entity and each of its affiliates.

3. A description of all assets, services and products provided by the regulated entity to non-affiliates.

4. A description of the cost allocators and methods used by the regulated entity and the cost allocators and methods used by its affiliates related to the regulated services and products provided to the regulated entity.

D. AFFILIATE TRANSACTIONS (NOT TARIFFED)

The affiliate transactions pricing guidelines are based on two assumptions. First, affiliate transactions raise the concern of self-dealing where market forces do not necessarily drive prices. Second, utilities have a natural business incentive to shift costs from non-regulated competitive operations to regulated monopoly operations since recovery is more certain with captive ratepayers. Too much flexibility will lead to subsidization. However, if the affiliate transaction pricing guidelines are too rigid, economic transactions may be discouraged.

The objective of the affiliate transactions' guidelines is to lessen the possibility of subsidization in order to protect monopoly ratepayers and to help establish and preserve competition in the electric generation and the electric and gas supply markets. It provides ample flexibility to accommodate exceptions where the outcome is in the best interest of the utility, its ratepayers and competition. As with any transactions, the burden of proof for any exceptions from the general rule rests ~~stays~~ with the proponent of the exception ~~utility~~.

1. Generally, the price for services, products and the use of assets provided by a regulated entity to its non-regulated affiliates should be at the higher of fully allocated costs or prevailing market prices. Under appropriate circumstances, prices could be based on incremental cost, or other pricing mechanisms as determined by the regulator.

2. Generally, the price for services, products and the use of assets provided by a non-regulated affiliate to a regulated affiliate should be at the lower of fully allocated cost or prevailing market prices. Under appropriate circumstances, prices could be based on incremental cost, or other pricing mechanisms as determined by the regulator.

3. Generally, transfer of a capital asset from the utility to its non-regulated affiliate should be at the greater of prevailing market price or net book value, except as otherwise required by law or regulation. Generally, transfer of assets from an affiliate to the utility should be at the lower of prevailing market price or net book value, except as otherwise required by law or regulation. To determine prevailing market value, an appraisal should be required at certain value thresholds as determined by regulators.

4. Entities should maintain all information underlying affiliate transactions with the affiliated utility for a minimum of three years, or as required by law or regulation ~~if longer than three years.~~

E. AUDIT REQUIREMENTS

1. An audit trail should exist with respect to all transactions between the regulated entity and its affiliates that relate to ~~jurisdictional~~ regulated services and products. The regulator should have complete access to all affiliate records necessary to ensure that cost allocations and affiliate transactions are conducted in accordance with the ~~previously mentioned~~ guidelines. Regulators should have complete access to affiliate records, consistent with state statutes, to ensure that the regulator has access to all relevant information necessary to evaluate whether subsidization exists. The auditors, not the audited utilities, should determine what information is relevant for a particular audit objective. Limitations o~~n~~f access would compromise the audit process and impair audit independence.

2. Each regulated entity's cost allocation documentation should be made available to the company's internal auditors for periodic review of the allocation policy and process and to any jurisdictional regulatory authority when appropriate and upon request. ~~Further, any jurisdictional regulatory authority may request an indepedent attestation engagement of the CAM.~~

3. Any jurisdictional regulatory authority may request an independent attestation engagement of the CAM. The cost of any independent attestation engagement associated with the CAM, should be shared between regulated and non-regulated operations consistent with the allocation of similar common costs.

4. Any ~~A~~audit of the CAM ~~does~~ should not otherwise limit or restrict the authority of state regulatory authorities to have access to the books and records of and audit the operations of jurisdictional utilities.

5. Any entity required to provide access to its books and records should make arrangements as necessary and appropriate to ensure that competitively sensitive information derived therefrom be kept confidential by the regulator.

F. REPORTING REQUIREMENTS

1. The regulated entity should report annually the dollar amount of non-tariffed transactions associated with the provision of each service or product and the use or sale of each asset for the following:

   a. Those provided to each non-regulated affiliate.

   b. Those received from each non-regulated affiliate.

   c. Those provided to non-affiliated entities.

2. Any additional information needed to assure compliance with these Guidelines, such as cost of service data necessary to evaluate subsidization issues, should be provided.

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RESOLVED, the NARUC directs the Staff Subcommittees on Accounts~~, together with the Subcommittees on~~ Strategic Issues and Gas, to review the Guidelines for Cost Allocation and Affiliate Transactions, taking into consideration the progression of competition in the electric and gas industries nationally and report their findings to NARUC, including ~~the~~ proposed changes to the guidelines, if necessary, on or before January 1, 2001, and annually thereafter; and be it further

RESOLVED, the NARUC applauds and thanks the Staff Subcommitees on Accounts, Gas and Strategic Issues for their excellent work in developing the guidelines.

Sponsored by the Committees on Electricity, Finance and Technology, and Gas